Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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PUBLIC UTILITIES COMMISSION

William A. Bonnet
Vice President
Government & Community Affairs

December 29, 2006

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street, First Floor
Kekuanaoa Building
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 05-0315 - HELCO 2006 Test Year Rate Case
Act 162 Consultant Report

In accordance with Order No. 23153, enclosed for filing are the original and ten copies of the Report on Power Cost Adjustments and Hedging Fuel Risks prepared by NERA Economic Consulting.

Sincerely,

William A. Bonnet

cc: Division of Consumer Advocacy
Keahole Defense Coalition, Inc.

December 29, 2006

Report on Power Cost Adjustments and Hedging Fuel Risks

Hawaiian Electric Company, Inc.

NERA
Economic Consulting

MMC Marsh & McLennan Companies

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I. INTRODUCTION

NERA Economic Consulting ("NERA") was retained by Hawaiian Electric Company, Inc. and its affiliates, Hawaii Electric Light Company ("HELCO") and Maui Electric Company ("MECO") (collectively, "HECO" or "the Utilities"), to evaluate whether its fuel adjustment clause ("FAC") – the Energy Cost Adjustment Clause ("ECAC") as it currently exists – is in compliance with Act 162, which was signed into law in June 2006.[1] In addition, HECO sought NERA's assistance with respect to fuel price hedging and other approaches to stabilizing end-user electricity rates to present to the Hawaii Public Utilities Commission ("HPUC" or "the Commission"). This report presents a summation of NERA's findings on these matters.

FAC mechanisms (and other similar cost adjustment and tracking mechanisms) give utilities a reasonable opportunity to recover their legitimate costs of procuring electricity on behalf of customers. By providing timely cost recovery for power costs, the amount of time between rate cases can increase. The breadth of adjustment clauses is not limited to fuel and purchased power expenses. Rather, the ECAC or a similar adjustment mechanism can be implemented efficiently for recovery of other costs that meet the three classic reasons for an automatic rate adjustment , which include:

1. The cost of the purchased resource is outside the control of the utility that purchases it.
2. The item accounts for a significant or large component of the utility's total operating costs.
3. Costs related to the resource are volatile and unpredictable.

Adjustment and cost tracking mechanisms may also be implemented to allow for the parallel treatment of similar costs categories. For example, demand-side management ("DSM") costs provide a substitute for pursuing supply-side resources. If supply-side resources are recovered under a FAC, DSM costs could be treated symmetrically, which would put supply- and demand-side energy costs on an equal footing.

The ECAC that HECO and its affiliates currently have in place is comparable to the FACs that are used by other traditionally regulated jurisdictions in the United States. Nearly all traditionally regulated and most restructured states in the US have some similar mechanism for power cost recovery. Like the ECAC, most (approximately 22) of the 30 restructured states with fuel clauses have some form of "true-up" mechanism to reconcile actual and forecasted costs. Also, thirteen of those states have rate adjustments on a quarterly or more frequent basis.

[1] A Bill for an Act Relating to Energy, S.B. No. 3185, S.D. 2, H.D. 2, C.D. 1, Act No. 162 signed into law by the Governor of Hawaii on June 2, 2006 (hereinafter, "Act 162" or "the Act") amended Section 269-16 of the Hawaii Revised Statutes to include a subsection (g) that specifies requirements for the design of "any automatic fuel rate adjustment clause," of which the ECAC is one.

Both fuel costs and purchased energy costs are recovered through the ECAC. A weighted average of the various fuel and purchased energy costs is computed monthly based on an estimated fuel mix. This is then converted to a rate for customers based on the estimated MWh sales for the month. An efficiency factor (MBtu/kWh) is used to calculate the conversion between the MBtu of fuel purchased and the amount of kWhs generated. The ECAC is updated monthly and an Energy Cost Adjustment ("ECA") factor is determined on a prospective basis. A reconciliation is done on a quarterly basis, which compares revenues recovered through the ECAC and revenues allowed using actual fuel mix, kWh sales and prices. The overcollection or undercollection is adjusted in the ECA factor for the following three months. The monthly ECAC filings with the Hawaii Public Utility Commission ("Commission" or "HPUC") ensures timely recovery of fuel and purchased energy costs for HECO.

Act 162 is concerned specifically with the incentive structure facing utilities. Just as it is important for utilities to have incentives to control—to the extent they can—fuel and purchased power costs, so too should ratepayers have a cost-based price signal. Ratepayers will not choose to consume an efficient level of electricity it they are shielded from the true costs of producing electricity and a timely FAC therefore has an important role to play. When consumers are aware of, and can respond to, the cost effects of their energy consumption decisions, they can reduce their demand when the price outweighs the benefit of consuming the product. The efficient allocation of resources concerns the price signals faced by customers. Failure to allow rates to reflect fuel and purchased power costs in a timely manner would distort this efficiency, since customers would be receiving an inappropriate price signal regarding the value in the market of the services they choose to consume.

II. COMPLIANCE WITH ACT 162

Act 162 incorporates five requirements for the design of any public utility automatic rate adjustment.

A. Fair Risk Sharing of Fuel Cost Changes

Act 162 requires that any automatic rate adjustment be designed to "[f]airly share the risk of fuel cost changes between the public utility and its customers." The risk of fuel cost changes is determined by:

1. Changes in the price of fuel as a single productive input; and,

2. Changes in the cost to deliver and produce electricity from HECO's fuel inputs. This reflects any changes in the technical ability of the utility to turn fuel purchased into electricity, which may require HECO to purchase a greater quantity of fuel, and thus increase the overall level of fuel costs, in order to produce the same amount of electricity.

Efficient risk sharing occurs when the party that has the means to control a cost has an incentive to do so. This distinction is critical because the price of fuel is, realistically, beyond the control of the utility. HECO acts as a price taker in the world-wide market for fuel (oil) and the design of the ECAC and the recovery of fuel and purchased energy costs should recognize this fact.

Accordingly, the ECAC acts to pass exogenous changes in input costs onto consumers. In fuel markets (as in other markets where HECO is a price taker—as in vehicles), it is straightforward to demonstrate prudent purchasing. There is a well defined market price and a well defined need to buy from this market (i.e., ratepayers' demand for electricity). In a price-taking market, "risk sharing" of fuel price changes would lead to no efficiency gains resulting from management incentives to minimize costs. Accordingly, changes in the price of fuel should be fully passed onto ratepayers. This would provide them with a price signal, which is an incentive to use resources efficiently. This supports the utility's ability to maintain its financial viability, and would increase regulatory lag—the time between rate cases—for costs that are within the utility's control, which would enhance the utility's incentive to control its base rate costs.

The ECAC, with its "heat rate" efficiency factor, provides a partial pass through of fuel and purchased power. It shares the risk/benefit of increased plant operating efficiency by tying HECO's ability to recover its fuel costs (and thus its financial performance) to its power plant performance over which it has managerial control, while also allowing HECO to pass through the exogenous changes in the price of an input over which it has no control, the price of fuel and purchased power.

HECO has considerable control over the operation of its plants—limited by engineering realities—and therefore it is reasonable, as the Commission already does, to provide HECO with an incentive to improve its operating efficiency to manage or lower its fuel costs. As discussed in the next section, putting fuel oil expense recovery at risk in an attempt to give the Company an incentive to look for non fuel oil resources would be an inefficient, indirect and counterproductive way of subsidizing renewables. Directly subsidizing renewables or enforcing renewable portfolio standards will increase the usage of renewable generation resources, but without having the perverse effect of harming the utility's financial position or distorting the cost recovery mechanism to favor one fuel cost over another.

The general role that management plays in an investor-owned, regulated enterprise should be recognized. Efficient and prudent management strives to minimize the amount of inputs while maximizing the production of the final product (*i.e.*, to maximize total factor productivity). Viewed from this perspective, management should have an incentive to manage efficiently the selection of inputs (of which fuel and purchased power are two of many)—and HECO does have this incentive.

This heat rate efficiency factor properly shares the risk of fuel usage decisions and recognizes that the added risk of cost recovery associated with plant operation is balanced with rewards from productivity increases.

State commissions in Florida, Louisiana, and North Carolina are examples of jurisdictions that have established specific incentives for power plant performance. A "Generating Performance Incentive Factor" is included in fuel and purchased power recovery clauses in Florida that rewards the utility (up to a 25 basis point spread) when its generation assets achieve certain performance benchmarks in availability and heat rate. In North Carolina, the allowed level of fuel cost recovery is linked to achieved nuclear capacity factors. These are reasonable approaches that provide the utility incentives to improve plant performance, something over which it has considerable control.

Because the ECAC contains an efficiency factor that transfers plant operation risk to HECO, but also passes uncontrollable changes in fuel prices to ratepayers, NERA concludes that the ECAC complies with the fair risk sharing requirement of Act 162.

B. Utility Incentives for Fuel Costs and Renewable Energy

Act 162 requires that automatic rate adjustment mechanisms "[p]rovide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy." This condition is closely tied to the previous one. Accordingly, the targeted efficiency factor promotes productive fuel use decisions and gives HECO an incentive to reasonably manage or lower its fuel costs.

If HECO achieves more efficient plant performance than the level of the efficiency factor (which, for example, is currently set at 0.11170 Mbtu/kWh), then HECO is rewarded. If it fails to meet this target for some reason, then it is not allowed to recover the additional expenditures required to produce the kWhs with the fuel it purchased.

The ECAC should cover all purchased energy costs, including renewable sources, on an equal footing within the cost recovery mechanism. Renewable energy resources can be part of a utility's power procurement to the extent that they are cost-efficient, reliable and represent a diverse source of generation relative to the traditional non-renewable resources. Like many utilities, HECO creates and follows an Integrated Resource Plan ("IRP"), which determines the extent of renewables used in HECO's fuel mix. The IRP process balances cost-minimization with resource diversity and other concerns. Like purchasing fuel oil from the oil markets, purchasing energy from renewables is not without risks. To ensure the efficient use of renewable resources, the ECAC would cover all purchased energy costs, including renewable sources, on an equal footing. Currently, the ECAC is adjusted each month for changes in the energy mix of the sources of fuel and purchased power. Under an equal footing structure, there is no disincentive from a cost recovery standpoint to purchase renewable energy. The encouragement of renewable energy above and beyond a treatment paralleling non-renewables (*i.e.*, direct subsidization) is a matter of public policy and should not be confused with energy cost recovery. The ECAC should provide no disincentive for HECO to purchase energy from renewable resources.[2]

The ECAC has positive financial implications and can improve a utility's credit ratings, thereby moderating the cost of capital borne by ratepayers. In addition, the utility serves as a counter-party for renewable energy companies, so its credit standing frequently serves as an important determinant of the financial viability of renewable energy projects. Weakening the utility's credit rating through partial power cost recovery could harm renewable resources that rely on utility counter-party credit to support their investments. Through the ECAC, HECO can retain its high level of credit worthiness and as party to renewable IPPS, which essential for IPP financing. By improving utility finances, the ECAC, in turn, accommodates renewable energy investors.

NERA concludes that a fuel adjustment clause with an efficiency target incentive that recovers renewable energy costs on an equal footing, such as the ECAC, complies with the incentive requirement of Act 162.

C. Management of Price Volatility

Thirdly, Act 162 requires automatic rate adjustments "to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts."

There are no free lunches in risk management. Hedging imposes real costs to the party that wishes to reduce its exposure to price movements. Although in years that prices rise, ratepayers may benefit from a price hedge, this will not be the case when prices do not rise or fall. In the long run, hedging programs can be expected to increase the overall level of costs associated with fuel and purchased power expenses. Accordingly, if there is a mandate for the utility to reduce

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[2] Including the capital costs associated with capacity purchases, such as renewable capacity purchases, in the ECAC (or a tracker mechanism that could operate in parallel with the ECAC) would be one way to ensure immediate cost recovery and thereby reduce any economic disincentive.

ratepayers' exposure to the potential rise in fuel costs, these hedging costs should be passed onto ratepayers.

Act 162 recognizes that there are options "commercially available" to customers that can mitigate price risk for customers. In principle, a utility can mitigate the risk of fuel cost changes through two forms of hedges:

1. *Physical hedges*, such as long-term supply and purchased power contracts and maintaining fuel inventories. The costs of existing contracts are included in the current ECAC computations.

2. *Financial hedges*. Generally, financial hedges either require payment to intermediaries in cash to bear risks or otherwise pay through giving up the prospect for lower future fuel prices. If utility ratepayers are willing to pay for the additional service of hedging their price risk, HECO must be provided a means to recover the costs it incurs. In order to do this and to give HECO a proper incentive to mitigate price changes on behalf of its customers, the ECAC would include recovery of financial hedging costs. Currently, the ECAC allows the recovery of the unhedged fuel costs, but is unclear whether financial hedging costs would be recovered in the ECAC.

In order to meet the electricity demands of its customers, HECO operates oil-fired power plants. HECO purchases the oil for these plants. HECO's position in oil is therefore a short physical position. HECO hedges its short physical position by entering into an offsetting long position in delivered oil. This long position is achieved through the companies' existing fuel supply contracts. These fuel supply contracts tie the price paid by HECO for oil to a base component. The base component is the month-to-date average of a third-party assessment calculated on the 20th of the month before delivery. For example, HECO's industrial fuel oil deliveries for January 2007 will be based on the average of the Platts Los Angeles Bunker C assessments from November 21st to December 20th 2006. The actual contract price includes taxes and a standard premium (based on quantity). Depending on the contract, the price may include a locational premium and adjustments for heat content, premia to Pertamina,[3] quality differentials and freight. In addition, the contracts provide for quantities and delivery of fuel that are more than sufficient to cover HECOs needs. Hence, HECO and HECO's customers are hedged with respect to availability and delivery of the physical commodities. HECO's fuel costs are variable as the price it pays will vary with the daily assessments for the terms of HECO's fuel contracts.

With respect to price, despite the fact that the price varies with assessment values, HECO is hedged from the perspective of the utility. HECO's physical fuel supply contracts are struck at floating assessments. Similarly, its electricity rates float in accordance with the prices of oil that HECO pays. As discussed earlier, this is a logical regulatory framework, since HECO has no

[3] The premia represent market premiums (or discounts) achieved in the spot market relative to a price assessment called the Pertamina Price Formula for LSWR.

control over world oil prices. The matching of variable fuel operating expenses with variable electricity revenues helps to assure the financial integrity of the utility, while providing an economically-correct price signal to customers.

The fuel hedging contracts referred to by the Act, if reasonably available, would only be entered into by HECO to meet the objective of mitigating oil price fluctuations for customers. Customers are exposed to fluctuations in world oil prices, while hedged against availability and physical delivery risks and costs. If HECO were to hedge, it would be to reduce this exposure. Of course, there would be a cost to reducing the exposure that may not be justified by the benefit. It should be noted that there are other alternatives (described in **Section IV**) available that may provide the similar benefits sought through hedging programs (*e.g.*, rate stability and reduced exposure to input cost increases), but would not require pursuing these potentially costly hedging options.

Therefore, NERA concludes that under HECO's current procurement strategies, the ECAC complies with the price stabilization requirement of Act 162. However, if there were demand from customers and/or a mandate from the Commission acting on behalf of ratepayers for a hedging program seeking to stabilize fuel costs, then recovery of the hedging and risk premium costs associated with physical and financial hedges would be included in the ECAC.[4]

D. Preservation of Utility Financial Integrity

The fourth requirement imposed by Act 162 on automatic rate adjustments is to "[p]reserve, to the extent reasonably possible, the public utility's financial integrity."

For modern utilities that operate in a world of volatile fuel prices an FAC is critical to:

- Reduce the volatility of utility earnings. Companies exhibiting large earnings volatility are typically those with most difficulty in tracking input costs.
- Provide the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.
- Lower the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating. Volatile wholesale power and oil and gas commodity markets have led the rating agencies to more closely

[4] At least 12 states (Alabama, Florida, Georgia, Louisiana, Iowa, Missouri, Mississippi, Minnesota, North Dakota, South Dakota, Nevada, Colorado and Michigan) allow the pass through of hedging costs and/or the sharing of hedging benefits between the utility and its customers, usually through their respective Power Cost Adjustments.

scrutinize cost-recovery mechanisms. Credit rating agencies, for example, recognize the need for robust and frequently updated FAC mechanisms.[5]

- Maintain HECO's liquidity. Because oil and other fuel expenses are a large portion of HECO's operational costs, the ECAC is needed to enable HECO to raise capital in time to meet expenses and investment requirements.

Utility regulators have long recognized the crucial role that cost-recovery mechanisms play in allowing the utility an opportunity to recover its costs. FACs permit a utility to recover its costs and assure the capital markets that the company can meet its obligations to shareholders and bondholders. Colorado provides an example of its Commission balancing the concerns of utility and its customers. The Colorado PUC explained its long-term use of FAC mechanisms by stating that it established its FAC in order to permit rapid recovery of increased costs over which the utility has no control. The PUC recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings jeopardizing the its ability to provide service.[6]

When approving the Arizona Public Service Company's ("APS") proposed Power Supply Adjustor, the Arizona Corporation Commission stated "we agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating" and that "an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity in a rate case and result in lower rates."[7]

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[5] Each of the three major credit rating agencies recognize the importance of FAC mechanisms. *Fitch* states: "[i]n today's environment, the safest bonds in the utility industry may be those of vertically integrated utilities operating under commission-approved mechanisms to recoup prudently incurred power costs. Such companies typically operate in supportive regulatory environments which continue to feel the need for healthy reserve margins of generation."

S&P also notes that "[a]utomatic pass-through mechanisms that hold companies harmless from uncontrollable costs, such as fuel or foreign exchange effects, are viewed favorably."

Moody's concludes that: "Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages."

See: *Fitch*, "Procuring Power in California: A Potential Stranded Cost," September 7, 2000, p. 4.
Standard & Poor's, "Rating Methodology For Global Power Utilities," Standard & Poor's Infrastructure Finance, September 1998, p. 66.
Moody's, "Credit Implications of Power Supply Risk," July 2000, p. 3.

[6] Before the Public Utilities Commission of the State of Colorado, "In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities," Docket No. 93I-702E, Decision No. C95-248, February 6, 1995.

[7] Before the Arizona Public Corporation Commission, In the Matter of the Application of Arizona Public Service for Approval of Adjustment Mechanisms, Docket No. E-01345A-02-0403, Decision No. 66567, November 13, 2003, p. 5.

As a frequently updated, fully reconciled pass through mechanism for a large and volatile expense, the ECAC plays a critical role. Continuation of the ECAC would allow HECO to more readily raise capital in the future. This will improve its ability to meet future infrastructure needs and preserve the level of service demanded by its ratepayers and the Commission. HECO recognizes this fact when it states in its most recent 10-K that:

> Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward–looking statements and from historical results include, but are not limited to...fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses.

Because the ECAC provides a transparent, well-structured and consistently-applied cost recovery mechanism that contains an efficiency incentive that HECO's management can readily affect, NERA concludes that the ECAC complies with the financial integrity requirement of Act 162.

E. Minimize Regulatory Costs

The fifth and final requirement established by Act 162 is to "[m]inimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

In general, FACs are designed to reduce regulatory costs by separating the volatility of fuel costs from the base rates. Calculations supporting the ECAC are submitted to the Hawaii PUC for review on a monthly basis. A number of states have similar monthly fuel clauses. Braulio Baez, the Chairman of the Florida Public Service Commission states in a Consumer Bulletin concerning fuel price adjustments:

> The action of removing fuel costs from base rates had the effect of reducing fluctuations in base rates. Both the utilities and their customers now had a better incentive to respond to fuel price changes. Because non-fuel expenditures are more stable than fuel expenditures, utilities were not only less likely to seek base rate adjustments, but any rising costs also provided the utility with a greater incentive to use other, less expensive fuels to generate electricity.[8]

The reduction of frequent base rate cases does not reduce the Commission's oversight of HECO's fuel and purchased power expenditures. Electricity FACs can allow for recovery of narrowly-defined categories of fossil fuel costs, nuclear fuel costs, purchased power, fuel transportation costs, and hedging costs among others.

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[8] Braulio L Baez, "Customer Bulletin," Florida Public Service Commission, April 2004.

To further minimize regulatory costs, regulators can see that any other cost category that meets the three criteria for an automatic rate adjustment discussed in the background section receive parallel treatment to those costs already included in the ECAC. Cost categories to consider including in the ECAC (or tracking in a separate adjustment clause):

- All fuel and purchased power costs,
- Purchased capacity,
- Hedging costs,
- Environmental compliance costs, and
- Any other costs specific to the jurisdiction.

The breadth of adjustment clauses are not limited to fuel and purchased power expenses. Rather, the ECAC or a similar adjustment mechanism can be implemented efficiently for broader categories of costs, which would help to assure that supply- and demand-side energy resources are treated symmetrically in the ratemaking process.

Uniformity across the utilities' ECACs reduces the administrative costs associated with using a FAC to recover fuel and purchased power costs. Treating the fuel and purchased energy cost recovery of one HECO subsidiary separately from another would require further and unnecessary utility and Commission resources devoted to the treatment of fuel and purchased power costs.

Therefore, because the ECAC allows HECO to readily recover in rates a significant and volatile cost over which its has little control, NERA concludes that the ECAC reduces HECO's need to file base rate cases and thus complies with the minimization of regulatory cost requirement of Act 162.

III. ASSESSMENT OF FUEL HEDGING OPTIONS

This section of the report addresses fuel hedging options available in the marketplace. It gives a general overview of the objectives of hedging, a description of available hedging strategies, a discussion of the oil derivatives market and potential implementation constraints facing HECO and its affiliates as they consider entering into a hedging program.

A. Objectives of Fuel Hedging

EEI defines hedging as "the attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks."[9] Hedging can, in principle, allow a firm to offset and reduce risk. Act 162 raises the question of whether HECO should hedge by reference to "fuel hedging contracts" as a commercially available means to mitigate the risk of fuel price changes.[10] Hedging with respect to energy commodities can take two forms: (1) physical hedges, such as physical supply contracts and fuel inventories; and (2) financial hedges, such as fixed-price financially-settled futures contracts and financial options contracts. As described in **Section II.C**, HECO already engages in physical hedging.

In regulatory parlance and in many industries, the term hedging most often refers to short-term (less than two years in duration) activities. This is because forward markets offer liquid price hedging contracts covering delivery periods that often extend only for one or two years forward. For the oil derivatives markets,[11] price hedging contracts are only reasonably available for periods of up to twelve months. This means that hedging contracts, if pursued by HECO, could only mitigate the impacts of oil price changes on costs and rates for a defined period such as one quarter or potentially one year. Fuel hedging contracts cannot be expected to cover durations longer than this.

Long-term hedging – i.e., hedging for multi-year periods – is a possibility for HECO, but cannot reasonably be achieved through commercially available fuel hedging contracts. Long-term hedging for HECO could be done through diversification away from oil-based generation. This diversification would require investment in non-oil based generation capacity, either by rate-based generation or through long-term contracts with non-utility generators. In addition, another long-term hedge could conceivably be the purchase of oil reserves. However, utilities that have purchased fuel reserves have almost universally regretted the decision and eventually disposed of the reserves. It is not recommended that HECO seriously consider this option.

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[9] EEI Glossary of Electric Industry Terms, April 2005.

[10] Act 162, (g) (iii).

[11] Derivatives are a term used to describe financial instruments whose value is derived from the price of an underlying commodity. Hence, an oil price swap or call option is a derivative as its value is based on the price of oil, the underlying commodity.

Hedging is most often done to lock in a range of outcomes. But, hedging creates costs and risks. Hedging will not necessarily produce the lowest-cost outcome in any particular case—and will, overall, raise costs because of the costs of implementing the hedging program. For a buyer of fuel like HECO, hedging may be perceived as a bad decision in hindsight if the buyer locks in a price and then market prices decline. Similarly, hedging may be perceived as a good decision if market prices increase after the buyer places its hedges. The utility, the regulator, and interveners must understand the costs and risks of hedging before a utility decides or is directed by its regulators to embark on a hedging program.

There are certain situations where firms face business or financial risks that make hedging particularly important. For example, if prices for the firm's product will remain relatively fixed as a significant input cost varies, then hedging that input cost may be necessary to protect cash flows and maintain financial stability. This will be the case when the firm is more reliant on a specific commodity than the industry in general and changes in that commodity's price have a disproportionately strong impact on market prices. This could also be the case when industry competitive pressures are so severe that product prices cannot rapidly adjust to meet changes in input costs.

Hedging also makes sense for firms whose financial structures are highly leveraged or for firms whose liquidity is dependent upon commodity prices or price spreads. Examples of such situations in the electricity industry include:

- an unregulated generator using coal or renewable fuel may only be viable if oil and gas prices are high and may only build if hedged by a long term contract at a fixed price.
- an unregulated generator using gas or oil may only be viable if spark spreads are high and may want to hedge spark spreads through forward power sales.[12]
- retailers in deregulated electric markets who sign fixed price contracts with customers will need to hedge supply costs to avoid losses that could exceed their liquidity limits.

The need to hedge in these cases arises because the entity has assumed obligations – debt, a contractual obligation to a third party, or an expectation by investors of stable earnings – that can only be achieved if prices of input commodities or spreads between input commodities are within a certain range. Hedging allows those firms to assure that input prices are within a certain range.

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[12] The spark spread represents the theoretical margin for a power plant. If a spark spread is a positive number, then the price of the power is higher than that of the fuel and the spread is profitable. If the spread is a negative number, the power is priced at less than the cost of fuel and is not profitable. The spread can be determined using the natural gas, coal, or heating oil futures contracts. Mathematically, Spark Spread (in $/MWh) = [Electricity Total Value - Fuel Total Value] / [Amount of Electricity Delivered]. See: New York Mercantile Exchange, Conversion Calculator: Spark Spreads, http://www.nymex.com/calc_spark.aspx (Accessed December 22, 2006).

The motivation for regulated utilities to hedge is different from the motivation of firms in competitive industries. Regulated utilities that manage their businesses prudently are entitled to stable cash flows as a result of the regulatory compact. Regulated utilities with highly variable fuel costs generally have fuel adjustment clauses in place that provide for timely and adequate recovery of costs.

Hedging by regulated utilities is oriented toward managing customer rates; its objective is to insulate customers from the price fluctuations in an underlying commodity. For example, some gas and power distribution utilities hedge the commodities they sell in order to provide a fixed- or near-fixed price to customers. Integrated utilities with generation may hedge fuel costs in order to reduce the impact of fuel price changes on rates.

Hedging programs are generally designed and implemented by utilities in collaboration with the commissions that regulate them. The utilities agree upon an objective with the regulator and then they clearly establish a program for achieving that objective. The need for a regulated entity to hedge is created by a specific and customer-focused objective. Therefore, it must involve considerable regulatory oversight and guidance.

B. Overview of Strategies Used By Buyers of Commodities

Buyers of commodities can use a number of different hedging strategies to manage short-term price risk. There are three products that are commonly used by buyers of commodities:

- Forward contracts.
- Call option contracts.
- Collars.

These are addressed in turn below.

1. Forward or Futures Contracts

A forward contract is an agreement between two parties to buy or sell an asset or commodity at a pre-agreed future point in time. A standardized forward contract that is traded on an exchange is called a futures contract. Forward contracts are in most cases struck at fixed prices. A fixed-price forward contract locks in the price of the underlying commodity for both the buyer and seller.

Basis risks are the price risks that a buyer would be exposed to if the buyer cannot find a forward contract for the specific commodity it needs at the delivery location it needs. If the marketplace does not offer forward contracts that exactly match the commodity and the location where the buyer takes delivery, the buyer may purchase derivatives for a different commodity whose price is highly correlated with the product the buyer wishes to hedge. In addition, the buyer could purchase the same commodity it needs but at a delivery location other than the one where it takes delivery. In these cases, the buyer faces the risk associated with changes in the difference in prices between the two commodities or the two locations. The changes in these price differences are termed basis risk. Forward contracts are not readily available for the oil products and delivery locations that HECO needs, which means that if HECO decides to hedge, it will be exposed to basis risk.

A fixed-for-floating swap is also akin to a forward contract. A fixed-for-floating swap is a contract between two parties under which one party agrees to swap a fixed price for a published index price on a notional quantity. A fixed-for-floating swap is economically equivalent to a fixed-price forward contract. The difference is that the fixed-for-floating swap is a purely financial instrument, while a forward contract generally anticipates physical delivery.

2. Call Option Contracts

A call option gives its owner the right, but not the obligation, to buy an asset or commodity on a specified date (the expiration date), for a specified price (the strike price). Call options cap the price that will be paid by a buyer for a commodity.

3. Collars

A collar is a portfolio of options that is used to assure that the price of a commodity is within a given range. A buyer of a commodity who wishes to put a cap and floor on the price paid would sell a put option and buy a call option. This strategy assures that the price of the commodity will be within a given range – i.e., no lower than the strike price of the put (the floor) and no higher than the strike price of the call (the cap).

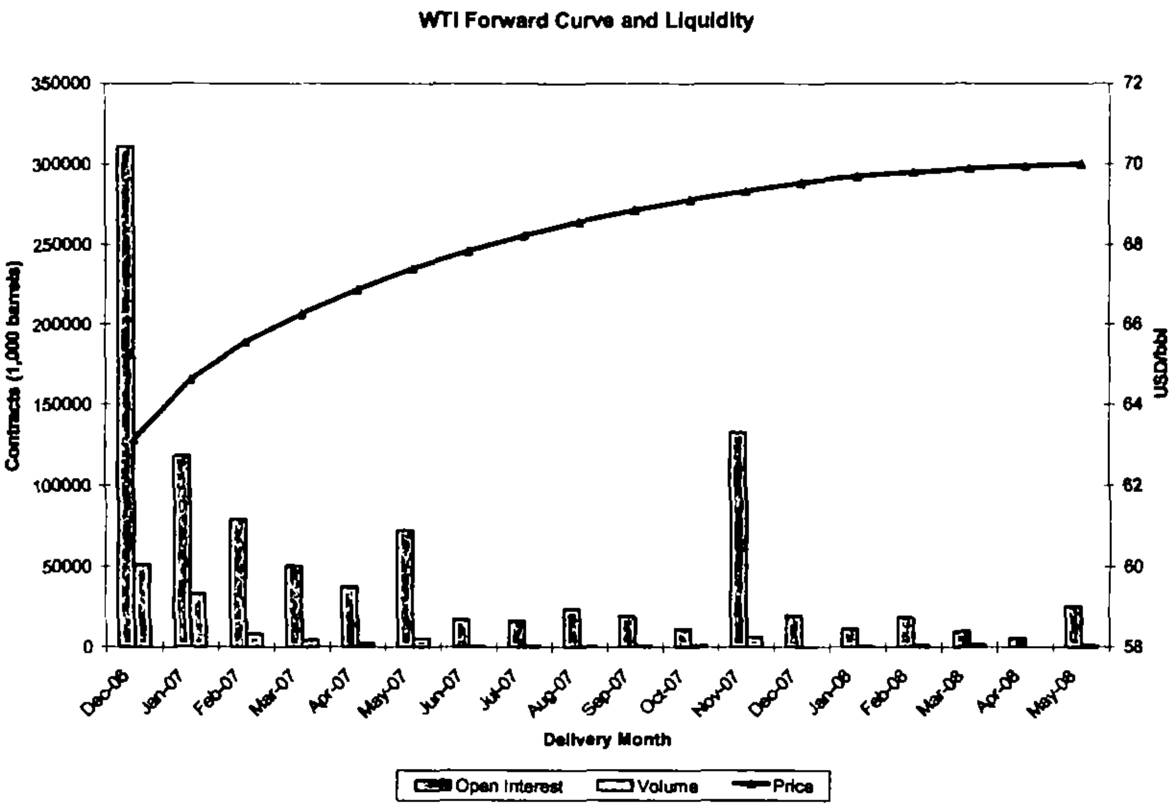
C. Characteristics of Oil Derivatives Markets

While the strategies outlined above work well in theory, they do not account for some of the practical considerations that must be considered with respect to implementing a hedging strategy. There are a number of practical implementation constraints that complicate hedging for HECO and its affiliates. These constraints are described below.

1. Duration of Derivatives

The first important constraint relates to the duration of the hedge. The forward and futures contracts that are traded in the marketplace do not reasonably extend beyond a term of 12 months. While there may be some quotes, the markets are quite illiquid beyond 18 months. Further, the most liquid (i.e., readily-available to trade) fuel hedging contracts are contracts that cover time periods of up to six months into the future. This is illustrated in **Figure 1** below.

Figure 1. Forward Curve and Liquidity in Oil Markets

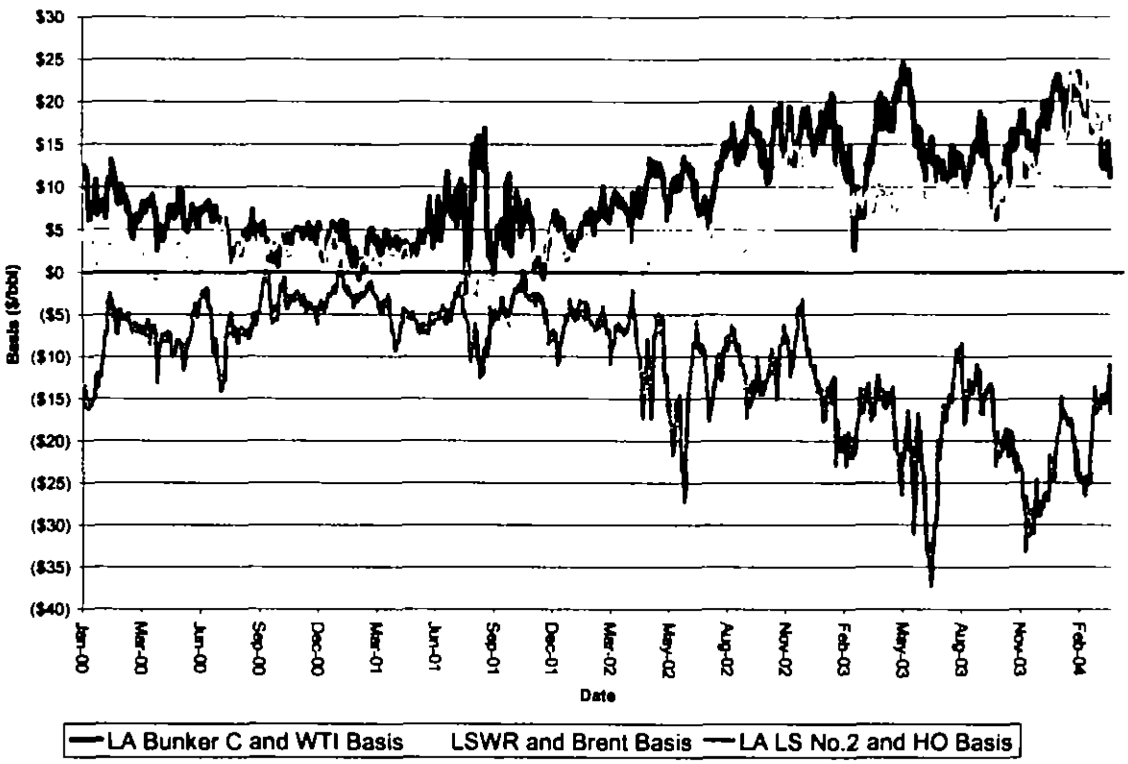


Notes: -The other fuel oils used by HECO (Heating Oil and Brent Crude Oil) display similar characteristics;
-Data as of November 30, 2006.

2. Delivery Points & Basis Risk

The second constraint faced by HECO and its affiliates is that hedging contracts for the precise oil products and delivery points that they would need are not visible in the marketplace. HECO would therefore be exposed to considerable basis risks if it used the oil derivatives that are readily-available in the marketplace. It is possible that a customized swap agreement could be obtained that hedges the price of the specific oil products in the specific locations that HECO and its affiliates need. However, such a swap is less transparent and it can be expected to be more expensive because the seller of such a swap would need to be remunerated for absorbing the basis risks and illiquidity of offering such a hedge. **Figure 2** illustrates the historical size of basis risks between the oil products that HECO and its affiliates use relative to spot prices of oil products for which HECO could obtain liquid hedges.

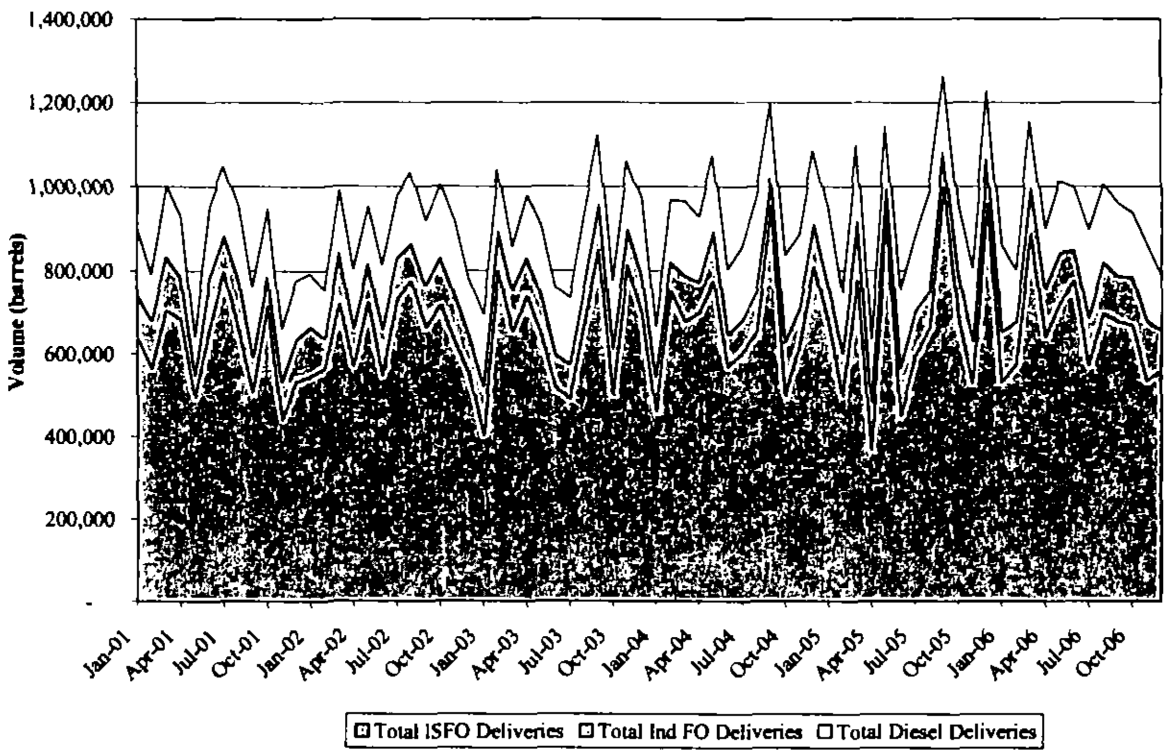
Figure 2. Daily Basis Risk for Heating Oil, WTI and Brent Fuels



3. Quantity Risk

The third constraint faced by HECO and its affiliates is the quantity they would hedge. The quantities that the utilities need of each type of fuel fluctuate month to month and year to year in accordance with changing demand, availability and relative economics of a generation plant, among other factors (as shown in **Figure 3**). The Utilities' existing fuel contracts provide for flexibility on the quantities taken, subject to a minimum and maximum take. The quantity flexibility embedded in the existing fuel contracts would be difficult to match in the financial derivatives markets, which offer fixed quantity products. If the utilities were to hedge the minimum expected quantity, their customers would face market risk exposure for incremental quantities, while hedging the maximum expected quantity would result in market risk exposure for decremental quantities. This quantity risk is important and makes accurate hedging difficult.

Figure 3. Quantity Risk: HECO's Monthly Deliveries of Fuel Oil Products



D. Implementation Issues

1. Credit Risks

If HECO and its affiliates decide to engage in hedging, they may face credit risk. Credit risk is the risk of a financial loss associated with the failure of a party to perform on its obligations under a hedging contract. Credit risk is an important factor when considering fuel hedging contracts. Market practice is to mark forward contracts to market and to collateralize the credit exposure embedded in forward contracts. This means that the value of the contract is calculated every day and any exposure must be covered as margin. If the utilities engage in hedging, counterparties may require that HECO and its affiliates provide collateral. The provision of collateral would add to the cost of hedging. Further, the utilities would, in most instances, be exposed to the risk of counterparty default and non-performance.

2. Liquidity Risks

The execution of fuel hedging contracts would expose HECO and its affiliates to liquidity risks. Liquidity is the ability to execute transactions in the marketplace. Markets that are highly liquid have active trading and many buyers and sellers. Market liquidity for oil derivatives ebbs and flows. When the markets are less liquid, a buyer or seller may face difficulties entering into or exiting positions. This is important because HECO or an affiliate may be forced to replace a position as a result of counterparty default. It is also important because it affects the price paid. In less liquid markets, it is more difficult for a buyer to get a good price. The risk that the markets HECO needs access to in order to execute or unwind and replace its hedge positions would not be liquid is a real one.

3. *Ex Post* Price Risk and Regulatory Scrutiny

It is not possible to predict the outcome of a particular hedging strategy before the fact. The ex post outcome will depend, to a large extent, on the price path of the underlying commodity during the hedging period. For example, assume that HECO fully hedges its fuel need with futures contracts at $40/bbl. No matter what happens to the price of oil from this point on, HECO will pay $40/bbl for oil. However, even though the initial hedge may have been perfectly rational *ex ante*, subsequent decreases in the price of oil will increase costs relative to a no-hedging strategy and increases in the price of oil will decrease costs relative to a no-hedging strategy. All hedging instruments contain similar risks relative to their respective strike prices. As the price of fuel oil changes, a prudent and reasonably managed hedging program implemented by HECO may become costly relative to another hedging strategy (including the strategy of not hedging at all).[13]

Like all potential costs and benefits to the utilities and their ratepayers, the risk of regulatory disallowance should be fully understood and examined prior to embarking on a hedging program. **Table 1** summarizes all of the costs and risks facing a utility implementing a hedging program.

[13] For an in depth treatment of this issue, see: Jeff D. Makholm, Eugene T. Meehan, and Julia E. Sullivan, "Ex Ante or Ex Post? Risk, Hedging and Prudence in the Restructured Power Business," *The Electricity Journal*, April 2006, Vol. 19, Issue 3, pp. 11-29.

Table 1. Costs and Risks of Hedging Programs

Administrative costs	▪ Corporate governance of hedging activities ▪ Risk assessment and control ▪ Cost of collateral postings ▪ Compliance with hedge accounting rules ▪ Up-front regulatory costs (cost of establishing hedging objective and hedging program including execution timeframe, contract types, contract duration) ▪ Ongoing regulatory costs of hedging proceedings
Market risks	▪ Market risks on incremental/decremental quantities ▪ Basis spread widens or contracts, thus reducing the effectiveness of the hedge
Credit risks	▪ Counterparty default risk
Liquidity risks	▪ Ability to unwind or replace positions
Duration of hedge	▪ Increase in market, credit and liquidity risks for long-dated hedges
Regulatory Risk	▪ Risk of hedging cost disallowances of a prudent *ex ante* hedging strategy that became costly.

E. Summary of Available Hedging Alternatives and Recommendations

It may be possible for HECO to hedge price risk for periods of up to 12 months into the future and, in the process, potentially provide customers with reduced (but not eliminated) exposure to sudden fuel cost changes. The process of executing hedges, setting rates based on the hedge costs, and informing customers of those rates would take time and the development of some level of expertise and sophistication on the part of HECO. Price hedging should not be expected to address rate periods more than one year at a time, nor should it be expected to insulate customers from long-term changes in the supply and demand for the resources used to produce electricity. Further, HECO could not reasonably hedge to eliminate all exposure to fuel cost fluctuations due to the multiple risks described above.

Were HECO to hedge, it would encounter periods during which it experienced gains on its hedges and other periods during which it experienced losses. The gains in large part would be offset by increased fuel purchase costs and the losses offset in large part by reduced fuel purchase costs. The ECAC framework would need to be revised so that the difference between the hedging gains and the increased fuel costs and the difference between the hedging losses and the reduced fuel costs were reflected in rates through the ECAC. This would cause HECO's fuel costs to fluctuate, but theoretically they would fluctuate to a lesser extent than they otherwise would. Hedging by HECO would not be expected to reduce fuel and purchased power costs and, in the long run, would be expected to increase the overall level of costs.

There are alternative mechanisms for achieving customer rate stability that could be more effective than hedging. Given the costs and risks of hedging described above, HECO and its affiliates could consider these options as an alternative to embarking on a fuel price hedging program. These alternatives will be discussed in the next section.

IV. ALTERNATIVES TO HEDGING

There is no compelling reason for HECO to use fuel price hedging as the means to achieve the goals of short-term customer rate stability and efficient fuel and power procurement practices. Two rate smoothing mechanisms will be discussed as potential alternatives to hedging programs. In addition, we will discuss the inclusion of power cost sharing conditions in traditional FAC mechanisms.

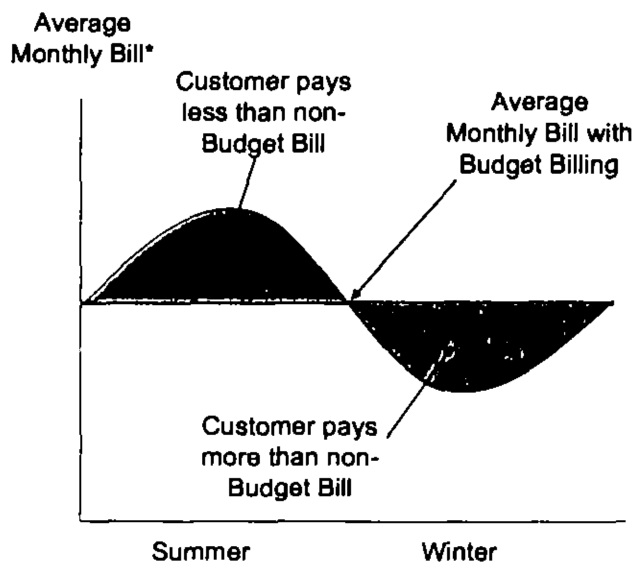
A. Rate Smoothing Mechanisms

This section presents an overview of two alternative rate smoothing ratemaking methods that could be used to provide customers with more stable rates in the short term, and in one case, temporarily limit customers' exposure to unexpected rises in fuel costs.

1. Budget Billing Rates

Budget billing is an "optional" payment program that allows the customer to pay the same amount each month for electricity or natural gas usage throughout the entire year. The voluntary nature of these programs limits any negative consumer feedback and targets the program to the consumers that want it. A monthly bill based upon previous usage patterns is estimated for the upcoming year as shown in **Figure 4**. At the end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan.

Figure 4. Budget Billing Example



* for a summer peaking utility

Budget billing is typically offered to residential and small commercial customers as part of a plan to manage volatile changes in monthly energy costs, usually to seasonal changes in consumption. It should be noted that budget billing does nothing to mitigate rising electricity costs. Participants still pay the full amount for electricity, only the timing of payments over the course of the year is adjusted. Most states currently have a form of budget billing program available to residential customers.[14]

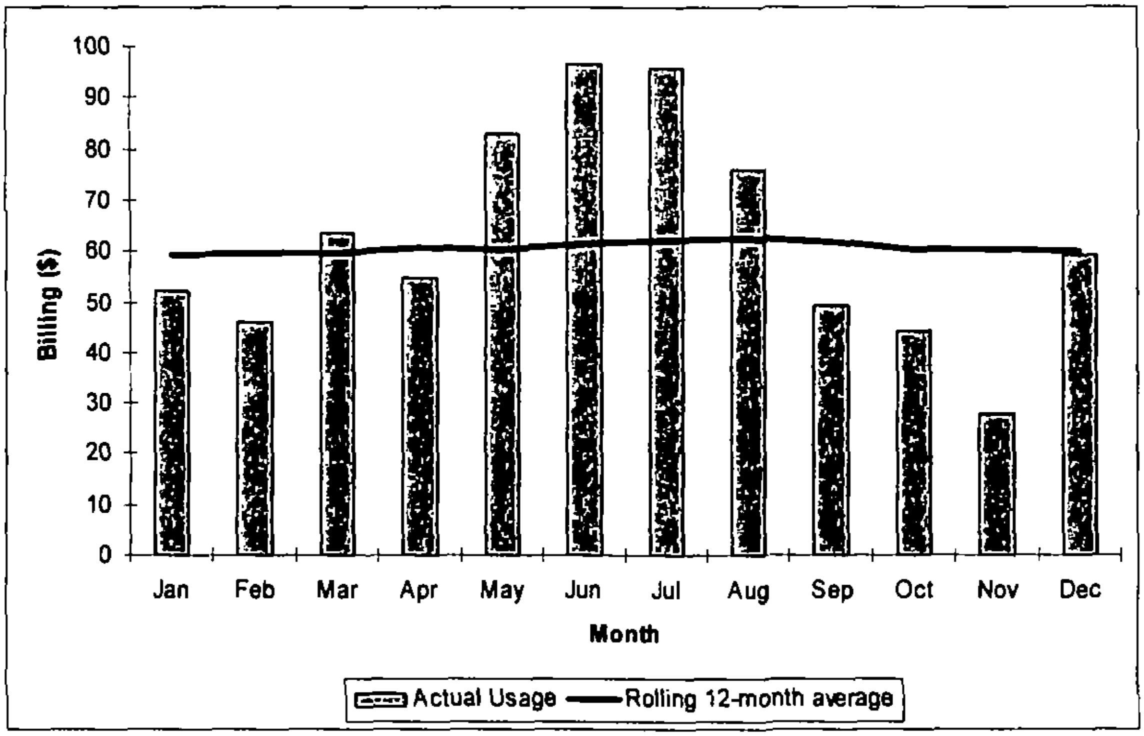
Budget billing has variations. For instance, NSTAR calculates its budget billing in the following fashion:

- Provides an equal payment from month to month based on usage for the previous year.
- At the end of the 12-month period, the Company reconciles any over or under usage from the estimate with the customer and sets the per-month payment for the next year.
- Reconciliation occurs in August/September time period each year.

An alternative to NSTAR's equal payment over a 12 month period is FPL's rolling average calculation for its budget billing. FPL calculates the bill for the current month by averaging the bills for the previous twelve months. As shown in **Figure 5**, this method results in slightly more volatility than NSTAR's equal payment plan, but allows the Company to recover their costs in a more timely fashion. The customer may also experience less true-up at the end of the period.

[14] In our survey, evidence of some form of budget billing was found in 47 U.S. states and the District of Columbia. Only Hawaii, Alaska and Rhode Island did not have a budget billing program.

Figure 5. Rolling 12-Month Average Budget Billing Example



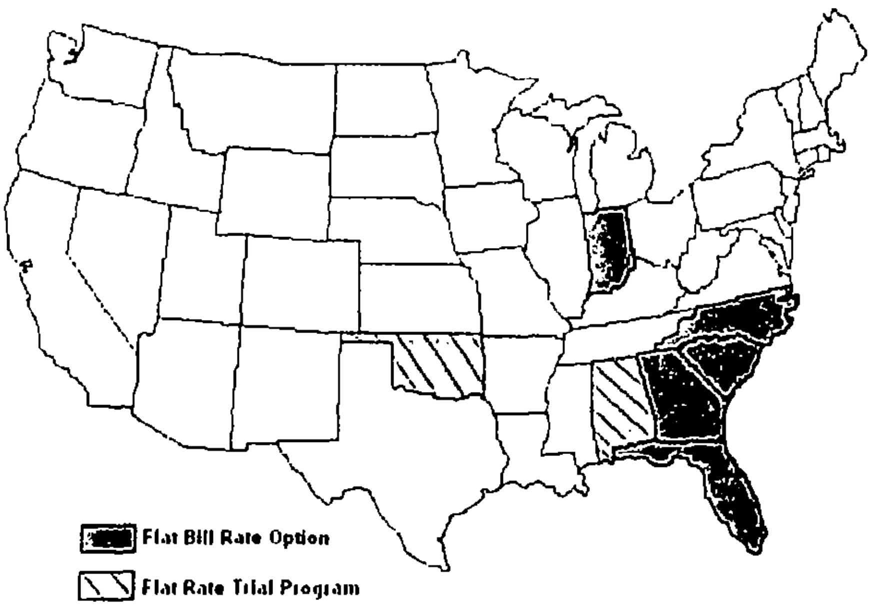
Source: Based on FPL's illustration found at: http://www.fpl.com/pay/contents/budget_billing.shtml (Accessed December 19, 2006).

The need for a budget billing plan in Hawaii may not be as large as most continental U.S. states due to the relative mild seasonality in demand. Nevertheless, budget billing may serve to aid low-income customers achieve rate stability, while perhaps helping the Company to decrease its uncollectible expenses.

2. Fixed Rate / Flat Bill Options

Some states have allowed utilities to have a rate option called "fixed rate" or "flat bill" in which a customer pays the same bill each month with no periodic reconciliation or true-up. The rates charged under these programs include risk premiums to reflect the risk the utility assumes by offering these programs. Fixed rate billing programs are generally available for larger commercial and industrial users who value (and are willing to pay for) insulation from unexpected price increases. **Figure 6** shows the states that have implemented flat bill rate options and trial programs.

Figure 6. Flat Bill Programs



Source: Michael O'Sheasy, "The Fixed Bill: Newborn Becomes Toddler!" January 4, 2005, http://topics.energycentral.com/centers/billing/view/detail.cfm?aid=900 (Accessed December 19, 2006).

Fixed rate billing is a voluntary rate option, which can help to identify customers that value rate stability. Voluntary rate plans can raise a whole host of issues, since customers will tend to switch to the plan that they find most advantageous. These issues include adverse selection, moral hazard and rate rebalancing issues.[15] In the case of fixed rate options, adverse selection and moral hazard problems may mean that only those customers who will alter their behavior to take advantage of the fixed rate nature of the program (*i.e.*, increase consumption without the risk of electricity price spikes) will be the customers that enroll. This was seen in Gulf Power's trial program where "Gulf noted that bills were adjusted by a 3.9 percent consumption adder only. The results of the pilot program showed an actual increase in kWh usage of 8 percent."[16]

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[15] Adverse selection and moral hazard are economic problems that result from incomplete or asymmetric information. When buyers and sellers have asymmetric information, trades actually completed may be biased to favor the party with better information. Adverse selection typically refers to information asymmetry that exists prior to the transaction and leads to a selection bias in the group participating in the activity. Moral hazard refers to information asymmetry that occurs after the transaction occurs. For example, insurance coverage may affect the behavior of the insured to undertake activities and risks that may change the likelihood of incurring losses.

[16] Florida Public Service Commission, Memorandum, Re: Docket No. 040442-EI – Petition for authority to implement proposed FlatBill rate schedule by Gulf Power Company, September 23, 2004, p. 6. http://www.psc.state.fl.us/agendas/041005cc/04100516.html (Accessed December 27, 2006).

The revenue neutrality of the rate design (or rate rebalancing) is achieved through proper construction of the fixed rate premium. However, designing a balanced optional tariff depends on many parameters, such as the actual size of the program, the size of any premiums and the behavior of the program's participants, many of which are not known and can only be estimated prior to the program.

A risk premium is necessary because fixed rate billing present costs and risks to the utility, leading it to incur additional costs. If fuel and purchased power prices are higher than expected, fixed rate billing will under-collect. The opposite is also true. Therefore, fixed rate billing effectively forces the utility to take a position in the underlying commodity market; therefore, the utility may make the business decision to hedge this exposure to the commodity markets. The costs of this hedging as well as any additional costs, such as any administrative costs and costs associated with any expected increase in demand by these customers, would necessarily be included in the fixed rate premium.

Fixed rate programs would offer a utility the ability to limit the risks typically associated with hedging fuel costs by limiting the program to those customers willing to pay for a price-hedged product. When evaluating Gulf Power's proposed fixed rate program, the Florida Public Service Commission ("FL PSC") discussed the magnitude of a risk adder:

> Gulf has indicated that two of the factors used to calculate a customer's FlatBill rate will be a risk adder and a consumption adder. The adders account for various types of risk that Gulf has identified in offering a customer the level bill...The proposed permanent program utilizes both a consumption adder and a risk adder. The risk adder recognizes that actual usage and response may differ from what Gulf expected. The risk adder reflects three sources of risk: modeling risk, weather risk, and price risk. Gulf estimated a 5% risk premium based on their Value-at-Risk methodology. This methodology requires as inputs an aggregate risk measure, which is based on the variability of the three sources of risk, and a cost of capital input...[The Commission recommended that] the consumption adder applied to the customer's forecasted annual usage [shall] not exceed eight percent (8%) and the risk adder, used to account for financial, weather, and other risks [shall] not exceed five percent (5%).[17]

Further, the FL PSC discussed how Gulf Power's fixed rate program can impact the utility's revenue requirement and profitability:

> Under the FlatBill program proposal, Gulf intends to determine the amount of revenues for earnings surveillance and other regulatory purposes by using the actual energy usage of the FlatBill customer and multiplying that actual energy usage by the otherwise applicable tariff rate including the appropriate cost

[17] *Id.*, pp. 6-9.

> recovery factors. The difference between the actual FlatBill revenues and the calculated "otherwise applicable" revenues would be *excluded for all regulatory purposes*. In other words, any FlatBill revenues in excess of the otherwise applicable revenues would flow to Gulf's shareholders. Conversely, the shareholders would absorb any loss if the FlatBill revenues were less than the otherwise applicable revenues.[18]

Ultimately, fixed rate billing provides benefits to larger customers similar to budget billing (rate stability) with the added benefit of insulation from input cost increases. Rates will, on average be higher for the customers who select this option.

B. "Risk Sharing" Mechanisms

Act 162 recognizes the impact an automatic rate adjustment can have on utilities and requires that a FAC provide a utility with an incentive to minimize – to the extent it can – fuel costs. As discussed earlier, the ECAC achieves this goal through the efficiency parameter, which is a targeted measurement of utility plant performance. Some states, however, have adopted partial pass-through mechanisms. Note that these are some times referred to as "risk sharing" mechanisms, but that characterization is incorrect given that a utility is a price taker, and would not be able to control the price of fuel and purchased power acquired from the market. **Table 2** provides a brief overview of these mechanisms.

[18] *Id.*, p. 9. (emphasis added)

Table 2. State Experience with Partial Pass Through Mechanisms

State (Utility)	Mechanism
Arizona (Arizona Public Service)	90 percent of any costs or savings relative to the base level would be allocated to customers and 10 percent is allocated to the company.
Colorado (Public Service Co. of Colorado)	Graduated sharing mechanism relative to a base level: The first $15 million is allocated 50/50. The next $15 million is allocated 75/25 between ratepayers and the utility, respectively. Any changes above $30 million are to be recovered from or flowed back to ratepayers. The maximum profit or loss that PSCO will absorb is $11.25 million in any one year.
Idaho (Idaho Power)	The power cost adjustment is 90 percent of the difference between the projected power cost and the base power cost plus the true-ups.
Washington (Puget Sound Energy)	Graduated sharing mechanism: PSE will absorb the first $20 million relative to the baseline, 50% of the next $20 million, 10% of the next $80 million, and 5% of any amount that exceeds $120 million. The Washington Commission also implemented a "power-cost-only rate case," so PSE can update its baseline rate to reflect changing power costs.
Washington (Avista)	Originally, the first $9 million is absorbed by the company (an $18 million deadband) and 90 percent of the energy cost differences exceeding the initial $9 million to be deferred for a later rebate or surcharge to customers. The parameters were modified in July 2006 to a $4 million deadband, a 50/50 sharing of energy cost differences between $4 million and $10 million and a 90/10 sharing of power costs in excess of $10 million.

These jurisdictions blur the distinction between risk sharing for productive purposes and risk sharing in the price-taking purchase of inputs. In other words, some jurisdictions impose risk sharing on the price of fuel and purchased power.

These cases are idiosyncratic and have generally represented a broad movement toward less risk imposed on the utilities involved in fuel and power purchases. In Arizona, FACs were suspended in 1989, but APS established a new one in a settlement to its 2003 rate case. Thus, APS went from no pass through to 90 percent pass through of fuel and purchased power costs. In Colorado, Public Service Company of Colorado ("PSCO") has other adjustment clauses for DSM costs, air quality improvement costs and purchased capacity that may compensate the utility for the increased fuel and purchased power risks. In its current rate case, PSCO extended its use of its fuel adjustment clause, but was also granted two associated incentive mechanisms: (1) if PSCO achieves coal production greater than a benchmark target, the associated savings would be shared 80/20 with customers; and (2) PSCO would share 80 percent of savings (above a deadband) related to the purchase of economic short term energy. In Idaho, Idaho Power absorbed all fuel cost changes prior to 1993, 40 percent from 1993 to 1995, and only 10 percent thereafter. Still, major deferrals occurred during Western Power Crisis (for later collection after contentious base rate proceedings). The story in Washington follows similar lines. Neither utility had a FAC and power costs were recoverable through base rate cases. Recent variations in hydroelectric generation supply (due to a seven year drought) increased the size of deferrals and threatened the utilities' finances. Avista filed a petition on January 30, 2006, proposing to eliminate the $18 million deadband of their Energy Recovery Mechanism ("ERM"). In a settlement, Avista's deadband was narrowed to $8 million ($4 million above and below the base level) with a 50/50 sharing of power costs between $4 million and $10 million and a 90/10 sharing of power costs starting at $10 million above or below the base level. The settlement also called on Avista to examine the cost of capital impact of the ERM, as well as the company's hedging strategy for fuel and wholesale power purchases. This represents another movement towards full pass through of power costs.

The fuel mix and thus exposure (and risk) to oil market price risk of the above utilities are also dramatically different than HECO, which relies heavily upon oil for its generation needs. **Table 3** shows that oil plays an insignificant role in these utilities' generation mix and its fuel and purchased power costs. Their large hydro, nuclear and coal resources mitigate much of their exposure to the volatile oil and natural gas markets.

Table 3. Fuel Mix for Utilities / States with Partial Pass Through Mechanisms

Fuel Type / Source	HECO[1]	APS[2]	PSCO[3]	Idaho[4]	Washington[5]
Hydro	0.5%	0.0%	0.0%	46.0%	66.0%
Coal	14.3%	39.3%	45.0%	47.0%	17.7%
Nuclear	0.0%	22.6%	10.0%	0.0%	5.3%
Gas	0.0%	9.1%	38.0%	6.0%	9.5%
Oil	79.3%	9.1%	0.0%	0.0%	0.1%
Renewables / other	5.9%	19.7%	7.0%	1.0%	1.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Sources:

1 HECO website, About Our Fuel Mix, http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=047a5e658e0fc010VgnVCM1000008119fea9RCRD&vgnextchannel=deeaf2b154da9010VgnVCM1000005301 1bacRCRD&vgnextfmt=default&vgnextrefresh=1&level=0&ct=article (Accessed on December 12, 2006).

2 Arizona Public Service, Generation Fuel Mix and Emission Characteristics, http://www.aps.com/_files/services/BusRates/disclosure.pdf (Accessed on December 18, 2006). Note that APS does not distinguish between gas and oil. They report that gas/oil comprises 18.2% of generation, for illustrative purposes this was split 50/50.

3 Xcel Energy Fuel Supply Sources, http://library.corporate-ir.net/library/89/894/89458/items/223379/12_6XcelUtilityWeekSECwAppendix12062006.pdf (Accessed on December 18, 2006)

4 Generation Options for Idaho's Energy Plan, presentation to the Subcommittee on Generation Resources, August 10, 2006, http://www.legislature.idaho.gov/sessioninfo/2006/Interim/energy_e3_0810.ppt#561,31,2005 Idaho Electricity Fuel Mix (Accessed on December 12, 2006).

5 State of Washington, Department of Community, Trade and Economic Development, Fuel Mix Disclosure, http://www.cted.wa.gov/site/539/default.aspx (Accessed on December 12, 2006).

A fuel efficiency factor is an incentive targeted at a utility's production decisions and isolates the utility's production performance directly. Partial pass through mechanisms are relatively rare, and have been adopted for utilities with no existing FAC in place. They should not be considered a viable option for fair risk sharing of fuel and purchased energy costs in Hawaii.

Fuel prices constitute a large and volatile cost for price taking utilities. A well established, frequently updated FAC is essential to maintain a utility's credit and operational viability. Partial pass through mechanisms that defer power cost recovery in an attempt to shield ratepayers from power cost changes present an inefficient solution to the rate stability issues and the rising cost of electricity input costs. Forcing a utility to temporarily absorb a portion of power cost changes (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) does not prevent consumers from ultimately having to pay the full amount for their power usage, and may harm the utility's financial position.

V. CONCLUSIONS

NERA's conclusions can be summarized as follows.

1. The ECAC framework that is currently in place for HECO and its affiliates is compliant with Act 162, but the eligible costs would need to be broadened if HECO were to engage in hedging using financial hedge products.

2. Short-term price hedging by HECO and its affiliates is possible in the oil derivatives market, but such activities would not eliminate fuel price fluctuations because ratepayers would continue to be exposed to basis risks, hedge quantity risks and other risks. In addition, hedging in the oil derivatives market would introduce new costs and risks for ratepayers. Fuel price hedging in oil derivatives markets is not, therefore, a compelling way to achieve the objective of customer rate stability.

3. Rate smoothing, in the form of budget billing or flat bills, is an alternative mechanism for achieving customer rate stability that could achieve the objective at a lower expected cost. NERA recommends that HECO and its affiliates consider rate smoothing in more detail.

Sharing of the risk of oil price fluctuations between customers and shareholders is not good regulatory policy when the utility has no control over world oil markets. Such sharing would not exempt consumers from ultimately having to pay the full amount for their power usage, (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) and thereby harm the utility's financial position.

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CERTIFICATE OF SERVICE

I hereby certify that on December 29, 2006, I served copies of the foregoing supplemental testimonies, together with this Certificate of Service, by hand delivery or carrier to the following at the following addresses:

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